Summary: Final Report, California Energy Commission (CEC) / New Power Technologies (NPT) / Southern California Edison (SCE) Project Using GRIDfast™ (December 2010) [1] - DER Summary

Outline of Topics Summarized

Project Background

This project was funded by the California Energy Commission Public Interest Energy Research (CEC PIER) program. It was performed by New Power Technologies (NPT), with GRIDiant

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[1] This Summary is based entirely on, and it excerpts or paraphrases directly from, the final project report: Evans, Peter (New Power Technologies) 2010. Verification of Energynet® Methodology, California Energy Commission, PIER Energy Systems Integration Program, CEC-500-2010-021, found at http://www.energy.ca.gov/2010publications/CEC-500-2010-021/CEC-500-2010-021.PDF. GRIDiant is responsible for any inaccuracies in summarizing or paraphrasing.

Corporation as a key technology subcontractor, and was hosted by Southern California Edison (SCE).

The project was designed to scale up (by more than 100 times), further test, and validate, in a large utility system, the NPT Energynet® power system simulation modeling methodology, using GRIDfast. In the Project, an integrated model of SCE's T&D system is modeled using multiple sources of existing data, and GRIDfast power system optimization and analysis software is applied to the T&D network model, as the optimization and ranking engine embedded in the network simulation methodology, for purposes of identifying and assessing various non-wires and wires/hardware measures, including optimized siting, sizing and dispatch of Distributed Energy Resources (DER), to improve T&D network efficiency, reliability, and other specific operational objectives and parameters.

In the Project, GRIDfast is applied for a variety of network optimization tasks, as summarized below.

Project Objectives

- Demonstrate the methodology's practical value to users and decision-makers by its enhancement of power network decision-making and problem solving.
- Assess the direct and indirect impacts and costs/benefits on T&D network efficiency, reliability, and other specific operational objectives and parameters of various non-wires and wires/hardware measures, including:
  (1) Bus-specific operational measures such as revised transformer settings, dispatching of capacitors, dispatching of Demand Response resources, other operational changes, system topology changes, and traditional capital development projects; and

  (2) Optimally-sited and -sized Distributed Energy Resources (DER), placed at specific buses in the project distribution network.

    i. DER included load control (Demand Response) resources, distributed generation (real and reactive, and renewable and nonrenewable) resources at customer sites, and re-chargeable storage resources (including electric vehicles).

    ii. The Project included actual field measurements for verification of project methodology and GRIDfast-generated project solutions.
- Develop a methodology for using GRIDfast and the Energynet model to show ways to improve system reliability through:
  (1) Reduced impacts of given contingencies.

  (2) Enhanced post-fault restoration (reducing outage time).

  (3) Identification of demand response and distributed generation capacity additions with specific benefits in reducing the impacts of given contingencies or enhance post-fault service restoration. (p. 48)

(4) Identifying and assessing the value of topology reconfiguration, distribution automation, and reliability improvement as quantifiable measures of network performance.

- Evaluate traditional network expansion measures alongside non-wires measures such as distributed resources and operational measures such as topology optimization and ideal control settings.

Project Integrated T&D Network

The project network that was modeled and analyzed was a piece of the Southern California Edison distribution system, fictitiously named the "Hobby System" for purposes of the Final Report. It was comprised of:

- 58 local transmission and sub-transmission substations
- 241 radial distribution feeders or circuits, voltages ranging from 33 kV to 2.4 kV
- 102 voltage-regulating devices (transformer taps and voltage regulators)
- 839 reactive power sources (capacitors)
- 30 embedded generation resources, some also sources of reactive power;
- 4,684 individually-addressable demand response resources
- System peak load approximately 1,300 MW
- 280,000 customers served at about 46,000 individual customer service distribution transformers
- 1,000 square-miles service area
- The Hobby System comprised nearly 100,000 buses (and their associated lines, transformers, loads and resources), connected to and integrated with approximately 15,000 buses that are part of a regional transmission model provided by the WECC.

Project Integrated T&D Network Models

- The researchers produced from different source data 15 separate models of the Hobby System, 7 reflecting the system on different "system dates," and 8 reflecting different possible future configurations. All were verified as having no unintended islands or inter-circuit ties. All but a few interim cases were populated with loads derived from actual SCADA records for a variety of conditions or forecasts and represented fully solved power flow simulations.
- The researchers believe these are the only examples of the successful development of integrated T&D power flow models of this scale from repurposed utility equipment and system data.[2] GRIDiant engineers used GRIDfast software to perform optimization runs of this system model in seconds, providing the engineer with strong direction as to next system resource or load adjustments to serve assigned system performance objectives, and allowing such modeling adjustments to be made easily.

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[2] Ibid., p. 67, p. 72

- The project demonstrated that major distribution system models can be developed in less than a month, which begins to be of potential interest for actual production-type work, especially if smaller-scale/incremental updates may reach sub-day update time frames. (p. 70)
- Notes on the 2005 Hobby System Baseline Network Models
    - The 2005 Hobby System's real and reactive losses were highest during the periods of highest loading. The distribution system comprised slightly more of the total losses than did the Hobby transmission system. In particular, as the system moves from a normal peak to a super-peak condition, it appears the distribution losses increase at a greater rate. (p.75)
    - In the Hobby distribution system, losses are not equally distributed. About 5% of all lines represent 95% of the total system losses. High-loss distribution lines are distributed; nearly every distribution circuit has some line segments in this top 5% of lines responsible for most of the system's electrical losses. (p. 75)
    - The Hobby system with the distribution integrated into a single model reveals far greater voltage variability than the Hobby transmission system alone... In the distribution portion … there is much more high-low variation, particularly in the summer peak and super-peak cases, and more also more voltage variability. Thus, the detailed Energynet® model reveals that a transmission-only look can mask deeper voltage issues in the distribution system. As expected, the more heavily loaded summer peak and super-peak cases reveal more transmission buses with low voltage and distribution circuits with low-voltage buses, and the more lightly loaded winter peak and minimum load cases reveal more high-voltage buses.

Technical Indicators of Network Performance

The primary technical indicators of network performance used in this study are:

    - Change in system-wide real and reactive losses.
    - Voltage impacts (generally impact on system-wide minimum voltage, also number of buses with voltage under 0.95 per unit (PU) and over 1.05 PU, number of circuits containing buses with voltage under 0.95 PU and over 1.05 PU).
    - Reliability impacts (generally the change in expected unserved energy).
    - Loading impacts (e.g. the change in the number of circuits with lines or elements loaded at greater than their normal rating).
- The project evaluated individual network performance enhancement measures for their capacity in megawatts (MW) and energy output in megawatt-hours per year (MWh/yr).
- Conventional power flow results allowed the project to determine changes to a modeled system in terms of real (P) and reactive (Q) losses, voltage, and equipment or line loading relative to normal or emergency ratings.

Objective Function for Optimization: Role of GRIDfast

One of the project's primary tools for identifying performance-enhancing measures beyond power flow modeling was GRIDiant Corporation's GRIDfast optimization technology for power systems.

- GRIDfast™ is an implementation of GRIDiant Corporation's patented[3] QuixFlow™ non-linear network analysis and optimization algorithm for electric power networks. QuixFlow directly employs inequality and non-linear constraints, rather than approximating them as linear constraints or equality constraints. Thus it can accurately evaluate, distinguish among, and rank resources for their benefit in a feasible system – that is, one where all constraints are met. Through QuixFlow's capability, GRIDfast can calculate the sensitivity of the entire network, in terms of magnitude and direction of movement toward or away from system constraints or optimization objectives, to a change of a resource at any point.
- In this project, with thousands of control variables in the SCE Hobby system and tens of thousands of potential locations for resource additions, GRIDfast™ calculated "resource sensitivity indices" (RSI) values describing the net impact of incremental (or decremental) resources at each point in the subject network in terms of performance relative to the assigned optimization objectives. As implemented in this project, the RSIs (sometimes referred to as P-Index and Q-Index) indicate either: a) the net benefit, relative to the assigned optimization objective(s), of incremental real (P) or reactive (Q) capacity at that location, or b) the extent to which the absence of real or reactive capacity at that location is adverse to the objective(s).
- Using GRIDfast™, the user can choose multiple simultaneous objectives that can be weighted. In this project, three GRIDfast software optimization objectives were applied simultaneously, placing equal weight on each: (1) minimize P (real power) losses, (2) minimize Q (reactive power) consumption, and (3) minimize voltage deviation from nominal among the buses and lines that make up the subject system. Because P and Q loss reduction also reinforces voltage profile improvement, voltage deviation is effectively the dominant element. Generally, this objective does not directly incorporate flow or loading. Therefore, overload reduction within this objective is an indirect result, as loaded lines cause greater losses and voltage drop, but not a direct result.

Network Performance Improvement Outcomes, and Financial Benefits

Idealized Network Recontrols

- GRIDfast™ can be set to re-dispatch all existing resources and available operational controls to an"optimum" configuration relative to the stated objective, or in this implementation, to that feasible configuration that minimizes voltage deviation from nominal, P losses, and Q consumption.

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[3] See Patent No.: US 7,660,649 B1, Resource Management Using Calculated Sensitivities, Gordon Hope and Soorya Kuloor, Inventors, Date of Patent, Feb. 9, 2010.

The researchers refer to this measure as "recontrol" or "ideal control settings". Based on discussions with SCE, the researchers specified available controls and resources in the Hobby system as:

  - All station capacitors (52 total in the 2005 system)
  - All line capacitors (787 total)
  - All transformer tap changers under load TCULs (89 banks total)
  - All line voltage regulators (14 total)
  - Reactive power output of all existing embedded generators with Q capability (13 units of 26 total)
  - For purposes of this study the researchers considered even the transformers with fixed taps as having variable sending-side voltages. The researchers also considered all capacitors identified in the system data as operational. Taken together, these represent 955 total controllable variable resources in the 2005 Hobby system, widely dispersed within the Hobby system.

- The project evaluated the use of the Energynet® model as a tool to identify those individual devices that would yield the greatest benefits in terms of network performance through their inclusion in a **distribution automation** scheme.
  - Recontrol results for the 2005 Hobby system presented in this report include simulations of the Hobby system with capacitor settings manipulated using GRIDfast™ to bring the system to its optimal operating condition relative to the stated objective under a variety of operating conditions. (p.37)
  - Because GRIDfast™ considers the impact of each element on the entire system, recontrols as applied here mimic a system-wide, centrally controlled system for dispatching these resources. (p.37)
  - Operating profiles of each of the system's capacitors were developed over the range of operating conditions encountered during the year. Those whose operating status should change frequently to maintain high-performance system conditions are identified as more valuable for automation. (p.38)
- 2005 Hobby System. In the 2005 Hobby system under summer peak conditions, of 787 distribution line capacitors, 219, or about 28%, were re-dispatched in the recontrol step relative to their as-found status taken from the SCADA records for each case. Under super-peak conditions, 182 were re-dispatched, and under winter peak conditions, 264 were re-dispatched. Note that, as stated above, the researchers assumed that all capacitors installed in the Hobby system are commissioned and available. In reality, some share of these would not be operational, and the capacitor inventory is designed accordingly. There were also changes to the transformer tap settings and the VAR output of existing distributed generation units. (p.89)
  - Under 2005 Hobby System Summer-Peak Conditions, GRIDfast recontrol-only optimization resulted in an improvement in Vmin (PU) of 0.047, and a reduction in P (active power) Losses of 3.239 MW.

  - Under 2005 Hobby System Super-Peak Conditions, GRIDfast recontrol-only optimization resulted in an improvement in Vmin (PU) of 0.036, and a reduction in P (active power) Losses of 2.445 MW.
    - Under 2005 Hobby System super-peak conditions, these changes raised to 0.95 PU or better the voltage levels of buses previously having voltages less than 0.95 PU in 14 different circuits occurring in 8 different 12kV and 33kV subsystems. (p.89)
  - Under 2005 Hobby System Winter Peak Conditions, GRIDfast recontrol-only optimization resulted in an improvement in Vmin (PU) of 0.046, and a reduction in P (active power) Losses of 1.304 MW.
    - Under winter peak conditions, these changes eliminated the buses with voltages less than 0.95 PU in all circuits (a total of nine circuits in 6 different 12kV and 33 kV subsystems). (p.89)
- 2009 Hobby System. In the 2009 Hobby System under Summer-Peak conditions, optimized recontrol of the system's transformer taps, capacitor dispatch, and VAr outputs using GRIDfast™ would reduce losses and improve the system-wide minimum voltage to where there are no buses with voltage lower than 0.95 PU. Under this optimized condition, the Hobby system's voltages are all within the ideal range. (p. 91)
  - Under 2009 Hobby System Summer Peak Conditions, GRIDfast recontrol-only optimization resulted in an improvement in Vmin (PU) of 0.026, and a reduction in P (active power) Losses of 1.383 MW.
- 2011 Hobby System. In the 2011 Hobby System forecast case under Summer Peak Conditions, optimized recontrol of the system's transformer taps, capacitor dispatch, and VAr outputs using GRIDfast™ does show that voltage-related objectives of the Hobby system as revealed by its performance under forecast loads can be largely addressed with existing resources. With optimized controls, the number of circuits with low-voltage buses is reduced to one, indicating that low-voltage issues noted in the Hobby capital plan in 5 different 12kV and 33kV subsystems systems would be resolved through ideal control settings. (p. 91)
  - Under 2011 Hobby System Forecast Summer Peak Conditions, GRIDfast recontrol-only optimization resulted in an improvement in Vmin (PU) of 0.026, and a reduction in P (active power) Losses of 1.383 MW (same values as for 2009 Hobby System Summer Peak Conditions). (p. 92)
- **Financial Benefits of Optimized Recontrols**
  - Utility operational projects benefits
  - Hobby System: 2011 Forecast
  - Project: Recontrols
  - Total Customer + Society Value ($/yr): $659,764
  - Total Utility + Utility Ratepayer Value ($/yr): $422,161

Re-Dispatch of Existing Demand Response

- For purposes of this study, “demand response” is dispatchable demand response only, i.e., load that can be reliably reduced on demand in response to a signal or order from the system operator, and thus is reasonably considered a system resource.
    - Accordingly, “demand response” does not include energy efficiency measures, which are not reductions on demand, or voluntary measures, which are not reliable load reductions.
- Demand response resources consist of both active or real power (P) and reactive power (Q) in proportion to the power factor of the load that is reduced.
- Some existing demand response resources in the Hobby system, when dispatched correctly, are valuable system resources in addition to means to reduce energy consumption under high load conditions. (p.38)
- For the 2005 Hobby System, GRIDfast was used to rank 4684 existing demand response projects in the system. 125 demand response resources were identified that alone would increase system-wide minimum voltage under super-peak conditions by 0.4% and reduce the number of low-voltage buses by 67, from 1,088 to 1,021. (p. 38, p. 92)
    - These 125 existing demand response projects lie on 11 circuits; further, 75% of the capacity represented by these projects is on just four circuits.
    - The next 875 highest-ranked existing demand response projects also yield meaningful voltage benefits. They increase the system-wide minimum voltage from 0.902 PU to 0.905 PU. They also increase the system’s median voltage from 1.00894 to 1.0090, reduce the voltage variability from 0.0193 to 0.0191, and reduce the number of low-voltage buses by 57, from 1,021 to 964.
    - The remaining 3,684 existing demand response projects have very modest voltage benefits.
- Accordingly, the evaluation of these individual projects also indicates where to obtain the most value through demand response automation ‐ automated, condition-based, individual, remote dispatch of demand response and possibly closer monitoring for performance. (p.38, p.92-3)

Distribution Automation – Enhanced Automation of Existing Demand Response

- The high-value existing demand response resources noted above could yield the related system performance benefits more effectively through the application of individual device level or circuit level dispatch, particularly where dispatch can be initiated for local system conditions rather than say statewide electrical capacity deficiency.
- The top 125 existing demand response projects identified above lie on 11 circuits altogether, and in fact, most of their capacity is on just four circuits. Therefore, providing or enabling device-level dispatch in these examples is a confined,

definable task. In light of the demonstrated value of these resources, there may also be an argument for closer monitoring to assess their availability and their performance when called. If a nominally high - value demand response resource were typically not responsive due to an equipment or communication malfunction, it would reasonably take on a higher priority for attention.

Re-Dispatch of Existing Distributed Generation

- The researchers identified 23 existing distribution-connected generation projects in the Hobby system that they modeled as having defined operating profiles. Of these, 11 have synchronous generators and the capability to produce or consume reactive power within normal generator limits. The researchers made these reactive power resources available as "recontrol" components, and the recontrol results presented above for both the 2005 Hobby system and the 2011 Hobby system reflect ideal dispatch of the VAR output of these resources.
- In terms of real power output, the Cogen, Hydro, and PS (Peak Shaving) resources listed among the 23 existing DG projects are dispatchable. As a default, the project assumed that these projects were available and operating during peak (daytime) periods, and in the case of the Cogen resources, available and operating during off-peak periods. The Solar projects are not dispatchable, and the project assumed as a default that they are available and operating during peak periods. (p. 93)
- The project evaluated each project and determined that at each project site real capacity at that location under the 2005 Hobby system conditions is on balance beneficial to the system's performance. Therefore, with all dispatchable projects operating during peak periods, there is no benefit to network performance from turning any of these resources down or off. Thus, the project concluded that as a network performance improvement measure there is no incremental benefit available from re-dispatch of the real power output of these particular resources.
- The project found that with very few exceptions existing distribution-connected generation projects representing VAr resources are optimally dispatched at a power factor other than unity, and that their ideal power factor changes as system operating conditions change. As discussed below, this suggests that to realize the full network performance benefits of the existing distributed generation resources, the reactive power capability of these generators should be made available to the network operator. Further, these resources should be included in a distribution automation scheme in which dispatch instructions are derived from actual system conditions and delivered to individual resources remotely. At the same time, the project found little value from dispatch of the real output of these units.

Optimal Additions of Distributed Energy Resources

- Project's Ordering of DER Additions. For the Hobby system cases, the project identified and modeled pure Q additions (capacitors) first, then demand response additions, distributed generation additions, and finally storage additions. The rationale for this ordering is as follows. The researchers presume the most cost-effective way to address a pure Q deficiency (after recontrols) is with capacitor additions. Likewise, demand response is most likely the lowest-cost resource among demand response, distributed generation and storage, followed by distributed generation, then storage.

  - The purpose of this approach is to ensure that benefits that could be achieved through capacitor additions are not ascribed to demand response and that benefits from demand response are not ascribed to distributed generation, a more costly and more difficult-to-acquire resource. Likewise, benefits that could be achieved through demand response and distributed generation should not be ascribed to storage. (pp. 44-45)
- Other Aspects of DER Additions Approach. Operating DER projects produce electrical energy that is, by definition, at the point of use or in the load center. So this energy potentially has value both in bulk system terms and, if applicable, in terms of avoided congestion or a location premium.
- In the project's view, the true incremental benefit of energy from DER is indirect, arising from its change in source location (potentially reduced congestion) or form of generation (potentially reduced emissions). In other words, bulk energy and congestion avoidance are in fact separate value streams; this is the approach the researchers took in this project. The bulk energy value of a given network measure may flow to the utility, its non-participating ratepayers, or the participating DER host customer, depending on contractual arrangements. Any congestion avoidance benefit of the measure accrues first to the delivery network operator, then to ratepayers depending on rate treatment, and any emission reduction benefit accrues to society.
- With guidance from SCE and the Energy Commission, the researchers imposed certain capacity limits and constraints on DER additions. These limits are intended to reflect the realistic high-side potential of these resources, the characteristics of the customer served at each site, and the characteristics of the system at that point. The limits incorporate prudent operational constraints on their penetration in the case of distributed generation.
- Using information supplied by SCE, the researchers populated the Energynet® model with the rate schedule and customer "class" of the customer(s) served at each of the roughly 45,000 load-serving transformers in the Hobby system, from which the researchers derived device- or bus-level DER limits.

Optimized Capacitor Additions

2005 Hobby System

- For the 2005 Hobby system, the Optimal DER Portfolio capacitor additions performed using GRIDfast consist of 157 capacitors at sites on 53 circuits. These capacitors are each either 150 or 300 kVAR in size, and in aggregate total 42,150 kVAR. 77 of these capacitors would operate under at least two of the five operating conditions the researchers analyzed, and 25 would operate under three or more. (p. 108)

  - Of the 157 capacitors, 22 capacitors on eleven circuits provide disproportionate voltage benefits under one or more of the operating conditions the researchers analyzed. Nine of those are on one circuit. Two capacitors, on two different circuits, are among those identified as providing disproportionate voltage benefits under every set of operating conditions. One of these would also operate under all five operating conditions, and the other would operate under all but the winter peak condition. (p. 108)

2011 Hobby System

- For the 2011 Hobby system, the researchers identified a set of Optimal DER Portfolio capacitor additions using a similar approach. The researchers identified 53 nominally beneficial capacitor additions, each added to the system in rank order according to voltage impact, and also identified their loss impact. These results suggest first that the 2011 Hobby system has nearly sufficient reactive power compensation capacity with existing resources used to their full advantage. Further, all of the 53 sites are on individual distribution lines; the researchers found no benefit relative to the objective in any additional substation capacitors. (p. 111)
- It is also evident that there are 3 individual capacitor additions that would yield nearly all of the potential benefits of the group of 53 capacitor additions relative to minimum voltage and loss improvement. These three capacitors are all located on a single circuit out of a single substation, the one circuit with buses having voltage lower than 0.95 PU after recontrols. Addition of just the first three-ranked capacitors, representing 300 kVAR each or a total of 900 kVAR, would increase the system-wide minimum voltage by 0.0096 PU or 0.96% of nominal, and reduce losses by 2.3056 MW. (p. 111)
- **Financial Benefits of Optimized Capacitor Additions**
  - Aggregate benefits of Optimal DER Portfolio capacitor additions
  - Hobby System: 2011 Forecast
  - Type: 3 Capacitors
  - Power Quality ($/yr): $241,814
  - CVR Value ($/yr): $4,903
  - P Loss Reduction Value ($/yr): $151,477

Optimized Additions of Demand Response

- The researchers considered as demand response load that could be reliably reduced on demand in response to a signal or order from the system operator. A factor, therefore, in setting realistic limits on dispatchable demand response is the availability and cost of controls and communication to effect on-demand load reductions.

- All Residential Customer Sites: Based on their rate schedule; candidate sites for HVAC cycling, a DR project could represent up to 25% of the peak load at that location, available only during super-peak periods. Such customers would in general have essentially no metering, communication, and on-site device controls to support other demand response projects. (p.40)
- All "Small Business" Customer Sites: Less than 20 kW demand based on rate schedule; candidate sites for HVAC cycling. A DR project could represent 15% of the peak load at the site, available only during super-peak periods.
- All Medium Business, Large Business and Industrial, Some Agricultural and Pumping Customers: Likely have more sophisticated metering, communication, and onsite energy management capability. Thus DR projects not necessarily limited to HVAC cycling, but might provide dispatchable demand response for system purposes during periods other than super-peak periods, though at lesser levels, and perhaps greater levels of demand reduction under some circumstances.
    - Medium Business Customer Sites: Between 20 kW and 500 kW demand based on rate schedule, and agricultural and pumping customer sites capable of dispatchable demand reductions of 2% of their peak load during either super-peak conditions or during periods other than super-peak. The researchers further assumed that 20% of these customers were capable of higher levels of demand reductions of 15% of their peak load during super-peak conditions.
    - Large Business and Industrial Customer sites: Greater than 500 kW by rate schedule, capable of dispatchable demand reductions of 6% of their peak load during super-peak conditions and 2% of their peak load during periods other than super-peak. The researchers further assumed that 60% of these customers were capable of higher levels of demand reductions of 15% of their peak load during super-peak conditions and 5% of their peak load during periods other than super-peak.
- SCE has a substantial number of customers with existing dispatchable demand response capability; the researchers modeled 4,732 sites in the 2005 Hobby system with existing demand response capability. The researchers modeled all of this demand response capability discretely; the researchers also assumed these customers were not available for additional demand response projects. The researchers assumed residential HVAC cycling resources to represent a fixed 2 kW increment, and non-residential HVAC cycling and interruptible resources to represent 15% of the customer's peak load; and in all cases, available only during super-peak periods.
- Some pumping and agricultural customers have arrangements that prohibit their operation during peak periods. The researchers assumed these customers were not available for demand response projects. The researchers have also assumed specially metered non-highway outdoor lighting loads and traffic signal load sites were not available for demand response projects.

- 2005 Hobby System. Applying these screens to the 45,916 load-serving sites in the 2005 Hobby system, there are 39,950 sites eligible for demand response additions, but only 3,313 sites eligible for demand response additions during periods other than super-peak conditions. Therefore, under these assumptions demand response as a resource class has far more potential under super-peak conditions. There are also 4,732 discretely modeled existing demand response projects, including 4,391 existing residential and small business HVAC cycling sites and 341 large business interruptible customers.
  - For the 2011 Hobby system Optimal DER Portfolio, the researchers followed essentially the same approach. However, without the benefit of different cases for different operating conditions the researchers simply assumed all demand response additions were continuously available as capacity but strictly limited in terms of annual hours.
- **The 2005 Optimal DER Portfolio includes 22,147 demand response additions representing available capacity of about 129 MW under super-peak conditions, or about 10% of super-peak load. 4,192 of these, representing available capacity of about 32 MW or 2.5% of super-peak load, are "voltage benefit" projects having disproportionate voltage impacts under summer peak, super-peak, and/or off-peak conditions. The nominal or project total demand response capacity is about 133 MW for the full 22,147-project portfolio and about 33.7MW for the 4,192-project portfolio**.
  - As a group when dispatched, these additional demand response projects raise the system-wide minimum voltage from 0.905 PU to 0.935 PU, an increase of 3.0 percentage points and reduce system-wide P losses from 65.786 MW to 53.936 MW, a reduction of 11.85 MW. They also increase the system-wide median voltage from 1.0090 to 1.0106, reduce voltage variability from 0.0191 to 0.0147, and reduce the number of buses under 0.95 PU by 461 from 963 to 502.
  - The 3,000 highest-ranked demand response additions have the most significant impact on system-wide minimum voltage under these conditions, increasing it from 0.905 to 0.919 PU. They also reduce voltage variability from 0.0191 to 0.0171 and reduce the number of buses under 0.95 PU by 223 from 963 to 740. These projects reduce the system-wide median voltage slightly from 1.00905 to 1.00891 PU but increase the system-wide average voltage from 1.0055 to 1.00609.
- 2011 Hobby System. For the Hobby System forecast 2011 super-peak conditions, the project identified and ranked the impact of over 23,000 nominally beneficial potential demand response additions on system-wide minimum voltage, each added to the system in rank order. (p. 115)
  - These additions together would represent 144.42 MW, or 8.46%, of the Hobby system's total load, and thus arguably represent an impractically large population of demand response projects. A loss analysis shows that there is little difference among the full set of 23,000 potential demand response

projects in terms of loss impacts. Among these potential demand response additions there is a subset of about 3,000 projects that are "high value" by virtue of their having a disproportionate impact in terms of voltage. (p. 115)

  - This high-value or "voltage benefit" subset of 3,000 demand response additions represents 14.93 MW, or about 0.87% of the Hobby system's load under these conditions. They lie on 55 different circuits, and increase the system-wide minimum voltage by 0.01290 PU or 1.29% of nominal when called or dispatched under these conditions. They would also reduce losses by 2.6695 MW when dispatched.
  - These demand response projects represent incremental capacity, available at least on a limited basis, to relieve localized peak period loads within the Hobby system *provided* they are dispatchable individually or by circuit.
- **Financial Benefits of Optimized Demand Response Additions**
  - Aggregate benefits of Optimal DER Portfolio demand response (A)
    - Hobby System: 2011 Forecast
    - Type: 3,000 DR Projects
    - Bulk System Capacity Value ($/yr): $984,148
    - Ancillary Services Value ($/yr): $671,962
    - Energy Value ($/yr): $192,184
    - Congestion Relief Value ($/yr): $1,339
  - Aggregate benefits of Optimal DER Portfolio demand response (B)
    - Hobby System: 2011 Forecast
    - Type: 3,000 DR Projects
    - Power Quality ($/yr): $324,937
    - CVR Value ($/yr): -
    - P Loss Reduction Value ($/yr): $186,962
    - Emission Reduction Value ($/yr): $48,593

Optimized Additions of Distributed Generation

- The researchers considered distributed power generation to consist of inverter-based generators, inductive generators, or synchronous generators. The researchers considered the use of inverter- and inductive-based generators in small distributed generation applications; these generator types have different VAR capability, and thus different impacts, than synchronous generators.
- The researchers assumed inverter-based generator systems would operate at a fixed, unity power factor; that is, they have only real power capability and no reactive power or voltage regulating capability.
- The researchers assumed inductive generator-based systems would introduce reactive load at a fixed rate of 0.5 Kilo volt-ampere reactive (kVAR) per kW of active power output. This is taken from the typical PQ characteristics of an uncompensated wind farm, which consumes approximately 0.5 MVAR per MW produced. While not all small inductive generators meet this power factor specification, some will be partially compensated, and the researchers feel this is representative of the group.

- The researchers assumed synchronous generators were capable of independently dispatchable reactive supply or load ranging from positive 0.5 kVAR to negative 0.33 kVAR per kW.
- 2005 Hobby System – Additions of DG
  - Of the candidate 45,477 sites in the subject system eligible for potential new distributed generation, projects at 19,381 sites are shown to yield network benefits under one or more of the operating conditions the researchers modeled. All of these are identified in terms of their location, generator type (synchronous, inverter, or inductive), and size in kW based on the nature of the underlying customer, and the period(s) during which projects in those locations are shown to yield network benefits. These sites lie on 207 of the 215 circuits of the subject system.
  - 15,301, or nearly 80% of these sites, are residential PV projects, and 1,769 are small business PV projects. The 2,311 projects that remain are a mixture of large-scale PV at medium and large business sites, inductive generation, and synchronous generation.
  - 5,934 of these sites are shown to yield benefits under all three peak conditions – summer-peak, super-peak, and winter-peak conditions. There are 616 additional sites that are shown to yield benefits under both summer-peak and winter-peak conditions, but not under super-peak conditions, possibly due in part to the impact of the large amount of demand response capacity added in the super-peak case. Of these 6,550 sites, 215 non-PV projects show benefits under light load hour conditions as well.
  - There are a total of 1,396 sites that are among the sites identified above as providing disproportionately high voltage benefits under one or more of normal summer peak, winter peak, or light load hour conditions. These lie on 72 of the 215 Hobby circuits. 73 of these sites yield disproportionate voltage benefits under both normal summer peak and winter peak conditions. 1,124 of these sites are residential and small business PV projects, and 71 are PV projects at medium and large business and agricultural sites ranging in size from about 2 kW to 32 kW.
    - This group of 1,396 sites includes 130 inductive generator projects ranging in size from 37 kW to 119 kW and 71 synchronous generator projects ranging in size from 3.6 kW to 1,030 kW. These 201 inductive and synchronous generator projects are dispatchable under the researchers' assumptions; 50 yield network benefits during summer and winter peak conditions and off-peak hour conditions and would ideally be base-loaded. Six should operate on a base-load basis but during the winter season only, and 68 should operate on a base load basis during the summer season only. Eleven plus one of the winter seasonal base-load projects should operate only during the super-peak day, but during both peak and off-peak hours. 66 should operate only during off-peak hours. As stated elsewhere, super-peak dispatch

        profiles may be affected by the large amount of demand response the researchers included in the super‐peak case.

        - The 73 projects that yield disproportionate voltage benefits under both summer peak and winter peak conditions lie on eleven of the 215 Hobby circuits. Researchers identified that 69 are residential and small business PV, one is an agricultural PV project, two are inductive generator projects, and one is a synchronous generator project. This synchronous generator project is a 180 kW project at a medium business site on the Malamute circuit that would operate at base load. Its rank among distributed generation additions under normal summer peak conditions is 568, and it is arguably the highest‐ranked traditional DG project in the Hobby system. It is interesting that most of the potential large synchronous generator sites ranked relatively low in terms of network benefits, probably because they are located at relatively robust parts of the system.

    - Under normal summer peak conditions in the 2005 Hobby system, the researchers identified 15,945 DG projects that nominally enhance network performance from 45,477 eligible sites. **As a group, these DG projects increase the system's lowest single-point voltage from 0.8989 PU to 0.9311, an increase of 3.2 percentage points, and reduce the system-wide voltage variability (standard deviation) from .0186 to .0158 PU. They also reduce the number of buses in the system with voltages under 0.95 PU by 415 from 1,154 to 739. As a group, these DG additions also reduce the system's real power (P) losses from 55.157 MW to 36.831, a reduction of 18.326 MW**.
    - These DG additions actually decrease the system-wide median voltage slightly from 1.009786 PU to 1.009152. As the researchers add capacity associated with these distributed generation projects, the potential for high voltage is offset by re-dispatch of capacitors and TCULs. This re-dispatch will allow some bus voltages to fall even if within the 0.95 PU -1.05 PU target range. In addition, the inductive generators add reactive load, potentially reducing voltage. Note that even as the median voltage decreases due to these distributed generation additions, the system-wide average voltage increases from 1.0059 to 1.0062 PU and the number of buses with voltages under 0.95 PU also decreases.
    - 1000 Highest-Ranked. Of these DG projects, about **1000 of the highest-ranked in terms of network benefits have a disproportionate impact on the system's absolute lowest voltage, bringing it from 0.899 PU to 0.935 PU. They also account for 346 of the 415 buses whose voltage increases above 0.95 PU.**
        - Because DG adds P capacity (or reduces P load), every incremental addition potentially reduces losses. The researchers found no obvious inflection point, though there is some observable decline in the loss benefit of each addition.

    - The sites of the 1,000 highest-ranked DG projects in terms of network benefits lie on just 30 of the 215 Hobby circuits, and about 90% of the capacity that this group of projects represents lies on only 15 circuits.
    - **Together these top 1,000 DG projects represent 9.05 MW, or an average of about 9 kW per project. The vast majority of these 1,000 DG projects, 924 to be exact, are residential PV projects. The remaining projects are all small and medium business distributed generation projects comprised of PV projects and smaller distributed generation projects – 11 are over 60 kW and the largest is 221 kW. There are no large industrial projects.**
- **It is interesting to look at the prominence of larger-scale DG projects in this set. Within the full set of 15,945 nominally beneficial DG additions for the 2005 Hobby system, there are 75 large DG projects at industrial customer sites, but individually they are relatively low-ranked in terms of network benefits. The highest-ranked among these is ranked number 1,681, and thus not included in the top-1000 “voltage benefit” group. The largest project in full set of nominally beneficial distributed generation projects is 3 MW. There are five more over 1 MW and 217 over 100 kW.**
- **Note that under super-peak conditions, the total capacity of the demand response - both existing and added in this case - of nearly 129 MW far exceeds the combined capacity of demand response and distributed generation that showed clear system minimum voltage impacts under normal summer peak conditions. Accordingly, the large volume of demand response capacity the researchers have assumed available under super-peak conditions effectively consumes the opportunities under these conditions to improve the system’s absolute lowest voltage using additions of real capacity. Accordingly, the additional benefit to system-wide minimum voltage from additional capacity from distributed generation projects is minimal. This suggests that if demand response were fully developed as a super-peak-only resource, it might go a long way to meeting critical period load reduction needs and provide significant voltage benefits. At the same time, the super-peak period value of other resources such as distributed generation might be quite modest.**
    - Under super-peak conditions, the researchers identified 15,520 DG projects that nominally enhance network performance from 45,477 eligible sites. As a group, these projects increase the system-wide minimum voltage from to 0.935 to 0.937. They also reduce the voltage variability from 0.01468 to 0.0140 but decrease the system-wide median voltage from 1.0106 to 1.00883. The impact of these projects individually on system-wide minimum voltage is highly indirect, and a “voltage benefit” subset is not identifiable. As a group, the 15,520 beneficial distributed generation projects represent 228.648 MW of capacity, or an average of about 15 kW per project.

    - They have no cumulative impact on the system minimum voltage, but reduce P losses from 53.925 MW to 35.650, a reduction of 18.275 MW.
- Under 2005 winter peak conditions, the researchers identified 7,988 DG projects that nominally enhance network performance from 45,477 eligible sites. As a group these distributed generation projects increase the system's lowest single-point voltage from 0.919 PU to 0.923, an increase of 0.4 percentage points, reduce the system-wide voltage variability (standard deviation) from 0.0150 to 0.0147 PU, and reduce the system's real (P) losses from 19.120 MW to 13.256, a reduction of 5.864 MW.
    - These distributed generation additions as a group actually decrease the system-wide median voltage from 1.010 to 1.007, increase the number of buses with voltage under 0.95 PU from 618 to 734, and decrease the system-wide average voltage from 1.007 to 1.004. This is due to the effect of the reactive load of the inductive generators and re-dispatch of TCULs and capacitors.
    - **The 285 highest-ranked projects in terms of network benefits, taken apart from the others, yield a greater increase in the system-wide minimum voltage, from 0.919 PU to 0.930 PU. This subset of projects also yields a reduction in the number of buses under 0.95 PU from 618 to 586.**
    - **As a group the full set of 7,988 beneficial distributed generation projects represent 129.46 MW of capacity, or an average of about 16 kW per project.**
- Under minimum load conditions, the minimum P Index bus has P Index equal to 0.40. This indicates that every bus in the system is nearly balanced or even slightly surplus in terms of real capacity. Accordingly, under these conditions, there are no demand response or DG projects that can improve network performance through the addition of real capacity.
- Under off-peak-hour conditions in the 2005 Hobby system, there are some real capacity deficiencies and opportunities to improve network performance through additions of real capacity, unlike under minimum load conditions. In addition, unlike any of the peak conditions evaluated, the many potential PV sites in the system cannot contribute. The researchers identified 858 DG projects that nominally provide network benefits under these conditions. As a group these projects increase the system-wide minimum voltage from 0.9726 PU to 0.9788 PU, they reduce the system's voltage variability from 0.0088 to 0.0081 PU, but they decrease the system's median voltage very slightly from 1.0170 PU to 1.0167 PU.
    - Essentially all of the improvement in system-wide minimum voltage comes from the 200 or so highest - ranked projects. Because distributed generation adds P capacity (or reduces P load), any increment potentially reduces losses.

  - The full set of 858 distributed generation projects as a group represents 122.285 MW, or an average of 143 kW per project. The average project size is larger as the group includes no residential PV projects. These projects also represent 17.211 MVAR of Q load due to inductive generators. As a group, these projects reduce P losses from 10.434 MW to 6.614, a reduction of 3.82 MW.
- 2011 Hobby System. The project identified a set of Optimal DER Portfolio DG projects for the 2011 ‑ forecast Hobby system using a similar approach. There are over 10,500 nominally beneficial (in voltage impact) potential demand response additions, each added to the system in rank order. These projects are all essentially the same in terms of their individual loss impact. A subset exists of about 3,000 potential distributed generation projects that are "high value" by virtue of their having a disproportionate impact in terms of voltage as measured by their impact on the system-wide minimum voltage. These projects would achieve nearly all of the potential voltage benefit from the entire set of beneficial DG projects.
  - The 2011 Optimal Portfolio of 3,000 distributed generation additions represents 46.86 MW, or about 2.75% of the Hobby system's load under these conditions. They lie on 73 different circuits and increase the system-wide minimum voltage by 0.0220 PU or 2.20% of nominal. They would also reduce losses by 5.9438 MW when dispatched under these conditions. Using the project specifications described in Section 2.2.6, this population of projects consists of 83% residential PV projects, 11.4% non ‑ residential PV projects, and 5.6% business and agricultural inductive or synchronous generation projects.
  - The total capacity represented by the 3,000 Optimal DER Portfolio distributed generation projects represents resource adequacy capacity directly or as reduced peak period load.
  - In addition, these projects represent incremental capacity to relieve localized loads within the Hobby system provided they are operational, and in the case of the inductive and synchronous units, operating.
- In terms of load relief, some of the projects on specific circuits served from specific substations could provide a deferral benefit. The capacity of the DG projects is more than enough to eliminate the normal ‑ condition overload on Music substation after allowing for planned load shifts. The DG projects on circuits served from Weckl and Metal substations are enough to eliminate the normal-condition overloads on those substations under forecast loads. However, the overloads on both substations are also relieved through planned load shifts.
- The capacity of the 2011 Optimal DER Portfolio DG projects can be mapped to the substations whose loading contributes to the elevated reliability risk of the highest-risk circuits in the Hobby system. The DG capacity on circuits

served from Bird and Tree substations is insufficient to permit those substations to continue to serve load under a loss - of - bank contingency. However, it could reduce the affected loads on those substations in such an event, assuming the substation remains in service at a reduced level.

- **Financial Benefits of Optimized Distributed Generation Additions**
    - Aggregate benefits of Optimal DER Portfolio distributed generation (A)
        - Hobby System: 2011 Forecast
        - Type: 3,000 DG Projects
        - Bulk System Capacity Value ($/yr): $3,198,992
        - Energy Value ($/yr): $21,944,520
        - Congestion Relief Value ($/yr): $180,606
    - Aggregate benefits of Optimal DER Portfolio distributed generation (B)
        - Hobby System: 2011 Forecast
        - Type: 3,000 DG Projects
        - Power Quality ($/yr): $554,156
        - CVR Value ($/yr): $11,235
        - P Loss Reduction Value ($/yr): $2,812,764
        - Emission Reduction Value ($/yr): $132,755

Optimized Additions of Distributed Storage

- Project definition of "storage capacity": Sources of real (active) power that can be sustained over a peak load period – i.e., for several hours. Storage was assumed to have siting flexibility to allow evaluation of its comprehensive value as a system resource. Accordingly, for purposes of this study, "storage" is not seasonal, it is not pure ride-through, and it is not necessarily pumped storage. Sample technologies for storage projects as the researchers consider them here include flow batteries, zinc bromide batteries, and, in over-1,000 kW sizes, sodium sulfide batteries.
    - Storage capacity must represent an active power load at the same location during a corresponding off-peak period. This requires a two-case optimization, as the optimization must consider both the impact of storage capacity available at each location during peak periods and the impact of storage load at that location during off-peak periods.
    - It was assumed storage capacity would consume power during recharge at a rate of 1.25 kW per kW of output (discharge) capability. Due to the need for the second, off-peak case, the researchers did not develop a storage component for the 2011 Hobby system Optimal DER Portfolio. Implied in this assumption is that storage at least for this project's purpose is not mobile within a daily period.
    - It was assumed storage capacity also represents a variable source of reactive power. Vanadium Redox VRB flow batteries offer active VAR compensation. It was assumed storage capacity represents plus/minus 1 kVAR of independently variable, sustained-output reactive capacity per kW of active capacity.

- General Approach to D Storage. The approach in identifying the 2005 Optimal DER Portfolio resources was to evaluate the incremental impact of each class of resources with the prior set in place and operating. Accordingly, at the stage where the researchers began assessing storage additions, the 2005 super-peak case was already populated with a very large amount of ideally-placed resources. Therefore, the researchers departed from the project's basic approach with storage additions simply to make the impacts of storage additions somewhat more visible. The researchers chose a configuration of the 2005 super-peak case that included the capacitor additions, the existing demand response, and the 3,000 highest-ranked demand response additions only, with no distributed generation differences. The researchers used the off - peak hour case incorporating the capacitors, demand response, and distributed generation projects identified above.
- With these two cases as starting points, the researchers chose to place incremental storage resources at those locations that would receive the highest net benefit from the storage resource on-peak and the storage load off-peak, or those locations with the greatest difference in P Index between the two cases.
- The project's approach with storage was to place a fixed "budget" of distributed storage of a total of 35 MW of nominal on-peak capacity. The researchers imposed a minimum size for storage addition increments initially of 60 kW, then subsequently of 10kW.
- 60kW Storage Increments. The researchers identified and ranked 493 storage "project" sites on 82 different circuits that yield net network benefits under the approach. Of these storage additions, most were composed of a single 60 kW increment. However, 54 were larger projects with multiple 60 kW increments, with the largest 360 kW. 14 circuits received high concentrations of storage additions, with total storage capacity additions on a single circuit greater than 700 kW.
  - Under super-peak conditions, these 493 storage projects yield identifiable network performance benefits. They reduce voltage variability slightly from 0.0171 to 0.0170 PU. Noting that GRIDfast™ is attempting to optimize to a voltage range that allows some pretty low voltages, there is little change to the system-wide minimum voltage, but the system-wide maximum voltage decreases from 1.050 to 1.044 PU, and the median voltage moves closer to 1.0 PU, from 1.0089 to 1.0080 PU. These projects also result in a loss reduction under super-peak conditions of 62.53 MW to 57.88 MW, or 4.65 MW.
  - As the peak-period voltage benefits of these projects appear less significant than the loss benefits, this may indicate that with the relatively wide voltage limits set for the optimization with the starting point the researchers chose there is little opportunity to "improve" voltage within those limits with P capacity additions.
  - **Project findings suggest that even relatively small storage devices - in this case as small as 60 kW - placed in locations in the power system where they would appear to yield high net benefits (that is, considering both the**

        off‐peak and on‐peak impacts) can introduce significant stress in those locations as they recharge.

- 10kW Storage Increments. A second Project storage case set 10 kW as the minimum size for storage additions. This smaller size allowed more distributed placement of storage devices. Under the assumptions discussed above, each 10 kW storage increment would have a charging load of 12.5 kW, an arguably consistent size with household storage devices such as electric vehicles in vehicle-to-grid (V2G) applications.
    - The researchers identified 1,488 storage sites on 93 different circuits that yield net network benefits. These storage additions are actually made up of 3500 rank-ordered 10 kW additions. Individually most of the storage projects under this set of assumptions are made up of single 10 kW increments; the largest is 6 increments, or 60 kW.
    - The circuits receiving the greatest total storage capacity are essentially the same as in the 60 kW case above, and in most cases in very similar total amounts. In effect, these storage projects are allocated to circuits similar to the 60 kW storage projects, but their capacity (and charging load) is more distributed within each circuit.
    - Under super-peak conditions, **these storage projects yield identifiable results. They reduce voltage variability from 0.0171 to 0.0168 PU, increase system-wide minimum voltage from 0.9187 to 0.9189 PU, decrease system-wide maximum voltage from 1.050 to 1.042 PU, and the median voltage moves closer to 1.0 PU, from 1.0089 to 1.0085 PU. Compared to the 60 kW additions, these storage projects reduce voltage variability more, 0.0168 compared to 0.0170 PU; they result in a higher system-wide minimum voltage, 0.9189 compared to 0.9181; they decrease system-wide maximum voltage more, 1.042 compared to 1.044. The system-wide median voltage for the 60 kW additions is slightly closer to 1.0, 1.0080 vs. 1.0085. These projects also result in a loss reduction under super-peak conditions of 62.53 MW to 58.01 MW, or 4.52 MW, slightly less than the peak loss reduction from the 60 kW additions.**
    - Under off‐peak conditions, with the storage units charging, the storage additions in 10 kW increments result in slightly less reduction in the system-wide minimum voltage and result in less loss increase compared to the 60 kW storage case. Under off-peak conditions with storage charging, the researchers found the system-wide minimum voltage fell from 0.9788 to 0.9773 PU (compared to 0.9695 PU for the 60 kW storage additions), and losses increased from 6.61 MW to 8.29 MW (compared to 8.40 MW for the 60 kW storage increments).
        - More importantly, with these units based on 10 kW increments in place for their charging, there are fewer areas with marked real power deficiency under off-peak conditions and the impact is less extreme. The only regions with P indices lower than ‐2.0 under off-

peak conditions are Cormorant and Carter circuits. Further, the P index values within Cormorant and Carter are much more acceptable; Carter has the lowest P Index points off peak, and the lowest points on that circuit have P indices of about ‑ 2.47.

- **This shows that smaller, more distributed storage additions have less adverse impact off-peak during charging. It suggests that there is a size of storage increment between 10 kW and 60 kW, below which these units can be sited for their maximum net on-peak and off-peak benefit with reduced or no risk of stress to the system off-peak due to the charging load.**

- <u>Third case, 60 kW Minimum Increment, Only At Sites Able to Accommodate the Charging Load Off-Peak</u>. This would necessarily reduce the ability to site these resources for their best net on-peak and off-peak benefit but might avoid adverse system stress off-peak.
- The researchers identified <u>354 storage sites on 80 different circuits that yield net network benefits</u>. Again, the circuits receiving the greatest total storage capacity are essentially the same as in the unrestricted 60 kW case above. Individually the majority of these projects are 60 kW. Researchers found 112 projects have multiple increments of additions (i.e. totaling 120 kW or more); the largest are 9 projects totaling 360 kW. Therefore, these projects are allocated to circuits similarly to the 60 kW projects in the unrestricted case but are in fact less distributed than the 60 kW projects in the unrestricted case.
    - These storage projects yield identifiable voltage benefits under super-peak conditions. They reduced voltage variability slightly from 0.0171 to 0.0168 PU. They actually lower the system-wide minimum voltage from 0.9187 to 0.9152 PU. They decrease system-wide maximum voltage from 1.050 to 1.045 and the median voltage moves closer to 1.0 PU: from 1.0089 to 1.0082 PU.
    - Compared to the earlier, unrestricted 60 kW additions, these storage projects are not as effective in terms of network benefits under on ‑ peak conditions. They reduce voltage variability essentially the same amount, but they result in a lower system-wide minimum voltage, 0.9152 PU compared to 0.9180 U, and they decrease system-wide maximum voltage less, 1.045 PU compared to 1.044 PU. The system-wide median voltage for the unrestricted 60 kW additions is also slightly closer to 1.0 PU: 1.0080 PU vs. 1.0082 PU.
    - Compared to the 10 kW additions, these storage projects are also not as effective. They reduce voltage variability essentially the same amount, but they result in a lower system-wide minimum voltage, 0.9152 compared to 0.9189 PU, and they decrease system-wide maximum voltage less, 1.045 PU compared to 1.042 PU. However, the system-wide median voltage for the 60 kW additions though restricted is slightly closer to 1.0 PU; 1.0082 vs. 1.0085 PU.

  - These projects also result in a loss reduction under super‐peak conditions of 62.53 MW to 57.92 MW, or 4.61 MW, slightly less loss reduction than the unrestricted 60 kW additions, but a slightly greater loss reduction than the 10 kW additions.
  - Though the differences are very small, these results show measurably that the 60 kW storage device additions, restricted by location, provide less voltage benefit under peak conditions than either the unrestricted 60 kW additions or the 10 kW additions, probably because the siting restriction prevents placement of these units' capacity for its best advantage on-peak.
  - The storage additions in 60 kW increments and at restricted sites as charging loads, result in slightly less reduction in the system-wide minimum voltage and less loss increase under off‐peak conditions compared to the 60 kW unrestricted storage case. Under off‐peak conditions the researchers found the system-wide minimum voltage fell from 0.9788 to 0.9736 PU (compared to 0.9695 PU for the 60 kW unrestricted storage additions), and losses increased from 6.61 MW to 8.31 MW (compared to 8.40 MW for the 60 kW unrestricted storage increments). Under off‐peak conditions the only region with P indices under ‐2.0 with these 60 kW storage units in place is Carter circuit, and the lowest point on Carter has a P index of about ‐2.25. Again, the P indices are acceptable.
  - **This suggests that siting restrictions are an effective way to mitigate the potential off‐peak impacts of larger storage units, and that in this case, with these restrictions, the larger 60 kW storage devices may be accommodated.**
- A closer look at the individual storage addition steps and projects lends support to these conclusions. Where 60 kW storage addition increments are unrestricted, the second storage addition step is the one that causes the most extreme system-wide off-peak P index to drop to extremely negative values. This particular storage addition is in Cormorant circuit, the circuit where the most extreme off-peak P indices also occur. When the sites for these 60 kW additions are restricted, no storage is added to this circuit, and the off-peak P index remains acceptable. When the minimum storage additions are set to 10 kW, a 10 kW increment is added in this circuit at this site, a second 10 kW increment is added at a different site on the same circuit, and the off-peak P index remains acceptable. Thus, in this instance adding storage in smaller and more distributed increments can mitigate off-peak P stress.
- Distributed Storage Summary. The project study on storage was intended more to understand and test the bounds of potential P stress off-peak from storage projects' recharging.
  - Based on this analysis, for the Hobby system the optimal DER storage projects consist of 1,488 storage sites on 93 different circuits totaling approximately 35 MW of on-peak capacity. These projects range in size from 10 kW to 60 kW; the majority are 10 kW projects.

  - These projects' capacity would be available under peak and super-peak conditions, and they would recharge at a rate of 1.25 times their rated capacity under off-peak conditions.
  - These storage projects comprise approximately 3,500 individual 10 kW storage increments. The 230 highest-ranked projects among these yield the greatest voltage benefit, as shown below. Stated in project terms these 230 additions lie on 119 individual buses on 26 circuits. Off-peak, as charging loads, the 1,488 projects increase losses and reduce voltage, but the researchers have shown that they do not produce high levels of stress.

Field Verification of Project Analyses

- The project demonstrated a side-by-side engineering evaluation with a benefit-cost evaluation adapted from a Navigant Consulting, Inc. methodology to provide a rigorous, data-driven comparison of different network performance improvement measures.
- NPT then developed a wide-area integrated sensor network on the SCE Hobby system, using legacy system sensors and, to fill monitoring gaps, new GridSense LineTracker current-sensing instrumentation and voltage sensors.
- **Field data from the sensor network verified the simulation model as a statistically valid predictor of field conditions: The variation of simulated voltage from field voltage at widely dispersed points in the subject system averaged 1.5%, well within the acceptable ± 5% operational voltage variation range.**

APPENDIX A

Further Detail Describing GRIDfast Technology and Applications

Objective Function for Optimization: Role of GRIDfast

One of the project's primary tools for identifying performance-enhancing measures beyond power flow modeling was GRIDiant Corporation's GRIDfast optimization technology for power systems.

GRIDfast™ is an implementation of GRIDiant Corporation's QuixFlow™ non-linear network analysis and optimization algorithm for electric power networks. QuixFlow directly employs inequality and non-linear constraints, rather than approximating them as linear constraints or equality constraints. Thus it can accurately evaluate, distinguish among, and rank resources for their benefit in a feasible system – that is, one where all constraints are met. Through QuixFlow's capability, GRIDfast can calculate the sensitivity of the entire network, in terms of magnitude and direction of movement toward or away from system constraints or optimization objectives, to a change of a resource at any point.

In this project, with thousands of control variables in the SCE Hobby system and tens of thousands of potential locations for resource additions, GRIDfast™ calculated "resource sensitivity indices" (RSI) values describing the net impact of incremental (or decremental) resources at each point in the subject network in terms of performance relative to the assigned optimization objectives. As implemented in this project, the RSIs (sometimes referred to as P-Index and Q-Index) indicate either: a) the net benefit, relative to the assigned optimization objective(s), of incremental real (P) or reactive (Q) capacity at that location, or b) the extent to which the absence of real or reactive capacity at that location is adverse to the objective(s).

Using GRIDfast™, the user can choose multiple simultaneous objectives that can be weighted. In this project, three GRIDfast software optimization objectives were applied simultaneously, placing equal weight on each: (1) minimize P (real power) losses, (2) minimize Q (reactive power) consumption, and (3) minimize voltage deviation from nominal among the buses and lines that make up the subject system. Because P and Q loss reduction also reinforces voltage profile improvement, voltage deviation is effectively the dominant element. Generally, this objective does not directly incorporate flow or loading. Therefore, overload reduction within this objective is an indirect result, as loaded lines cause greater losses and voltage drop, but not a direct result.

RSIs can also be thought of as measuring system "stress." In other words, the real power RSI, or "P Index" or the extent to which the addition of incremental active power resource at a particular point would move the entire system closer to the objective of minimized losses and voltage deviation, is arguably a measure of the "P stress" at that point, and likewise for the reactive power RSI. Changes to these indices were used as one measure of performance in the SVP Project. In this case, the researchers found these indices to be strong indicators of measures that would yield benefits in terms of voltage and losses, but volatile and indistinct direct measures of those benefits.

This use of RSIs calculated using GRIDfast™ provided a systematic, repeatable way to select from among a large number of resource addition alternatives, identifying those operational measures and network resource additions that would provide the greatest voltage and loss benefits by meeting real (active) and reactive resource deficiencies at individual points in the system.

In the project, NPT then demonstrated a side-by-side engineering evaluation with a benefit-cost evaluation adapted from a Navigant Consulting, Inc. methodology to provide a rigorous, data-driven comparison of different network performance improvement measures. NPT then developed a wide-area integrated sensor network on the SCE Hobby system, using legacy system sensors and, to fill monitoring gaps, new GridSense LineTracker current-sensing instrumentation and voltage sensors. Field data from the sensor network verified the simulation model as a statistically valid predictor of field conditions: The variation of simulated voltage from field voltage at widely dispersed points in the subject system averaged 1.5%, well within the acceptable ± 5% operational voltage variation range.

APPENDIX B

Optimized Alternate Network Topologies, Existing Network

(Including Automated Switching)

Networked Topology, Existing System

- In this exercise, consideration is given to joining (networking) radial circuit substations and systems where the connections are not between circuits of the same substation.
- 2005 Hobby System. The researchers evaluated networked topologies as described in Section 2.2.7 for the 2005 Hobby system through a series of sequential switch closures or networking “steps” implemented in order of their posited impact on system performance as estimated through an GRIDfast™ optimization. Each successive step results in an increasingly networked system, until all existing tie switches are closed and the system is fully networked by definition. The researchers considered a set of 563 existing, open inter-circuit ties as candidates for networking. (p. 94)
    - Nearly all of the impact on the system minimum voltage of all of the potential steps is achieved within the first 30-40 steps. This confirms the researchers’ expectation that a few networking steps would yield most of the benefit. The top-ranked 37 steps, if implemented, would increase the overall minimum voltage by 0.045 PU, or about 5%. (p. 94)
    - The loss impacts from increased networking are less focused on a high-impact group, but visibly begin to decline around Step 350. The highest-ranked 350 steps would achieve real power loss reduction of 7.44 MW, without adding any new resources to the system. (p. 94)
    - Among the 37 highest-ranked networking steps under this set of conditions, there are 28 unique circuit pair ties. In other words, only a few circuits are represented in these high-value networking steps, and several of those circuits are represented more than once. (p. 96)
    - Under super-peak conditions, the researchers found a similar voltage inflection point, indicating a set of high-value networking closures, even though the overall voltage improvement is not as great due to the loading of the system.
    - Under winter peak conditions, the initial voltage conditions are better, and the improvement from particular high-value networking switch closures is less distinct.
    - The researchers conclude that a “lightly meshed” system topology would achieve most of the same benefits of a fully networked system, particularly in terms of mitigation of system-wide minimum voltage.

    - Considering the superset of the “high-value” networking switch closures across different operating conditions, the researchers identified 128 switch closures. Of these networking switch closures, 15 would be implemented under all conditions, or permanently, 4 would be implemented only under summer peak and super-peak conditions, and 19 would vary from season to season, turned on and off under different conditions, for a total “portfolio” of 38 networking switch closures. The remaining 90 switch closures would only be implemented under winter peak conditions. In light of the relatively small voltage benefit networking under winter peak conditions, the researchers would judge them highly discretionary. (p. 97)
- 2011 Hobby System. The researchers also conducted a study of the potential benefits to the 2011 Hobby system of alternate topology, specifically networked topology. The researchers simulated the sequential closure of the available inter-circuit ties, going from a radial topology to a fully networked topology, in order of the impact of each switch closure on voltage and losses as assessed using GRIDfast™. Analysis suggests that the impact on the system-wide minimum voltage from networked topology is relatively modest; except at step 37, which happens to join the system’s one low-voltage circuit to a higher-voltage sibling circuit. Analysis suggests that there is an ongoing improvement in voltage variability, and increasingly flat voltage profile, with declining marginal benefit setting. (p. 99)
- Regarding the loss impact of networked topology, it is evident that the first 14 or so networking steps yield a considerable loss benefit; to achieve the same level of loss reduction with further networking steps would require many closures and a more heavily networked topology. (p. 99)
- The researchers conclude that a partially networked, or “lightly meshed” system topology can yield meaningful network performance benefits, and in some cases would achieve most of the same benefits of a fully networked system, particularly in terms of mitigation of system-wide minimum voltage. (p. 99)

Optimized Radial Topology, Existing System

- The researchers decided to carry a topology optimization study for the 2005 Hobby system through 20 “steps,” each step consisting of a switch closure paired with a switch opening, initially to assess the efficacy of an approach that would retain the radial topology of the system. (p. 102)
    - Each “step” commenced with identifying for closure the tie switch showing the largest difference in P resource deficiency using GRIDfast™. The researchers then used the topology features of the Energynet® model to identify a second switch to open to retain the

        radial topology of the system. The researchers implemented both changes, and then re-solved the power flow. (p. 102)
    - The researchers found that usually exists more than one sectionalizing switch that could be opened to configure radial system. To illustrate, opening either one of the main circuit breakers of the two circuits joined through the closed tie would return the topology to radial; however, neither is likely to be a desirable choice. In choosing, the researchers considered the direction of the load shift and the share of the circuit shifted. (p. 102)
    - The researchers adapted the GRIDfast™ analytics to show not only the difference in resource deficiency across an open switch but also the sign, to reveal the appropriate direction of the shift. Determining the share of the circuit to shift remained at least partially a matter of judgment and trial and error. (p. 102)
  - The researchers repeated this process for summer peak, super-peak, off-peak, and winter peak operating conditions. In each case, the researchers viewed the set of 20 steps as a single high-value group, with the ranking among them or the individual contributions of each step not material. The researchers believe this process could be fully automated, making it much more practical. (p. 103)
  - When compared to the voltage impacts of networked topology under super-peak conditions above, it is evident that this type of radial topology optimization cannot yield the same level of voltage improvement as even slightly networked topology can.
  - A comparison with the loss impact of networked topology above suggests that optimized radial topology of this type will not have an appreciable loss benefit.

<u>Distribution Automation – Switch Automation</u>

- The researchers found discrete, quantifiable potential network performance benefits that would require, and result from, routine manipulation of certain individual, identified switches in the Hobby system. These performance benefits arise from: a) seasonal or daily topology changes to maintain optimized topology, discussed above, and b) reduced restoration time through post-contingency load shifts. Therefore, high-value candidates for switch automation are those individual switches shown to have a recurring role in maintaining optimal topology or whose automation alone would change posited post-contingency load restoration times. These switches are thus attractive candidates for remote control and monitoring, with quantifiable potential benefits attributable to that capability. (p. 107)
  - Comparative analyses of switch automation alternatives depends in part on whether a utility chooses to maintain a radial topology policy or whether it will engage in some degree of networked topology.

- The reliability assessment the researchers performed included consideration of the circuit‐level reliability impacts of the availability or absence of automated switches for post‐contingency load transfers. Of the 215 circuits in the 2005 Hobby system, 169 reflected some level of increased risk for unserved load in the researchers' analysis due to limited post‐contingency load transfer opportunities or capacity under at least one set of operating conditions. Accordingly, switch automation alone would not directly address these reliability issues. However, the researchers found 98 circuits with adequate post‐contingency load‐transfer opportunities and capacity under all operating conditions, but no automated tie switches. Automated switches on these circuits would arguably provide a direct reliability benefit as a purely standalone measure.
- The researchers also found 65 circuits that have available load transfer opportunities and automatic or remotely operable tie switches. Additional switch automation on these circuits would arguably have less incremental impact on reliability, though there may well be individual load transfer operations that would be expedited with additional automation.

APPENDIX C

Reliability Benefits of DER Additions

Reliability Impacts of DER Additions

It is important to reiterate that the Optimal DER Portfolio projects described above are defined using an optimization/ranking approach designed primarily to reduce losses and voltage deviation. In contrast, the reliability assessment methodology the researchers demonstrated in this project is driven by loading and the interplay of loading and topology. Accordingly, the nominal reliability benefits of the Optimal DER Portfolio projects are somewhat of an indirect result. An alternative optimization/ranking approach could focus entirely on DER projects sited and operated to provide load relief with meaningful reliability benefits. This approach is incorporated in Reliability Optimization below. Having said that, the results and findings here demonstrate a rigorous, objective approach to assessing the reliability impacts of a set of projects that is relevant under either approach.

The researchers evaluated the impact of the 2005 Optimal DER Portfolio Projects on reliability through two mechanisms ‐ load relief opening additional post‐contingency load shift opportunities and load relief reducing otherwise elevated failure risk. For DER capacity to improve reliability by opening up additional post‐contingency load shift opportunities, the researchers viewed that two conditions must be met. First, the DER capacity must provide enough load relief to move a circuit from ineligible to eligible to accept load shifts. Second, the relieved circuit must serve as a backup to another circuit having compromised load shift opportunities. 131

The researchers found that distributed generation projects on two circuits represented sufficient capacity to open those circuits to post‐contingency load transfers and in doing so, enhance post‐contingency load transfer opportunities of “sibling” circuits that otherwise would have compromised load transfer options. In each case, the impacts would occur under normal summer peak conditions. The researchers found that demand response projects on four circuits represented sufficient capacity to open those circuits to post‐contingency load transfers and also, in doing so, enhance post‐contingency load transfer opportunities of “sibling” circuits otherwise having compromised load transfer options. In each case, the impacts would occur under super‐peak conditions only. Because super‐peak conditions represent such a small share of the operating year, the overall impact on reliability in annual terms of the demand response projects on these four circuits is much smaller.

Of the circuits with line segments loaded at over 120% of normal rating under one or more operating conditions, only Peach had enough demand response capacity to eliminate the condition, under super‐peak conditions. Again, because this benefit occurs under a small share of the operating year, the measured overall impact of the Peach circuit demand response projects on reliability is small.

Table 28 and Table 29 show the circuits of each of these sets of DER projects, the circuits whose reliability they affect (through expanded post‐contingency load transfer opportunities), and the annual reliability impact of these DER projects. The reliability impact is expressed as the change in expected outage hours, the change in expected unserved energy in kWh terms, and the change in expected unserved load in value of service terms.

It is evident that when reliability is measured in terms of unserved hours or kWh per year, DER measures having a material impact during a significant share of the year, such as during all normal summer peak hours, emerge as having a much greater nominal reliability benefit. The two circuits whose posited reliability is most improved, Ketch and Towel, are among those in Hobby with relatively high overall expected outage risk, in large part due to the insufficient post ‑ contingency opportunities of those two circuits. Optimal DER Portfolio DG projects on Blanket and Net, respectively, open up needed post ‑ contingency load shift capacity for Ketch and Towel under all normal summer peak hours. Thus, the expected unserved load risk on Ketch and Towel is reduced, and the reliability impact attributable to the DG projects on Blanket and Net is material. In the case of the Blanket and Ketch circuit DG projects, just the improvement in the interruption risk they provide for their affected circuits is greater than the average interruption risk for the system as a whole.

The researchers also analyzed the 2011 Optimal DER Portfolio demand response and distributed generation projects on individual circuits for their impact on circuit loading as it affects reliability. There is Optimal DER Portfolio capacity on seven circuits with segments loaded at greater than 120% of their normal ratings, the level at which the researchers assume a reliability impact. However, of these, only relief on Mussel circuit would have a quantifiable impact on reliability. The other circuits have sufficient alternate sources that they do not have reliability risk under this project’s rubric. The total reliability impact of the DER capacity on Mussel circuit in terms of circuit overload relief, shown in Table 30, is a 497 kWh/yr reduction in expected unserved load.

There are 42 circuits with Optimal Portfolio DER capacity that serve as alternate sources for circuits with constrained load shift opportunities and that are loaded to where they are not available to take post ‑ contingency load shifts. Load relief on these circuits in principle should have a reliability benefit. Excluding those circuits with very small amounts of total DER capacity in the portfolio and those for whom the reliability impact is small, the researchers identified 25 circuits whose DER projects that would yield a meaningful reliability impact in term of reduction in expected unserved kWh per year by expanding post ‑ contingency load shifts, or, in one case relieving a circuit overload. These results are listed in Table 30. 133

The 2011 Optimal DER Portfolio projects do not have sufficient aggregate capacity within any substation to permit that substation to operate through a loss ‑ of ‑ largest transformer bank contingency, thus they do not reduce any circuits’ risk of unserved load due to a transformer contingency.

Reliability Optimization

As stated in Section 2, in this portion of the study, the researchers sought to develop and demonstrate a methodology that would use GRIDfast™ and the Energynet® model to show ways to improve system reliability through principally the following means:

- Reduced impacts of given contingencies.
- Enhanced post‐fault restoration (reducing outage time).
- Identification of demand response and distributed generation capacity additions with specific benefits in reducing the impacts of given contingencies or enhance post‐fault service restoration.

For this portion of the study, the researchers considered initially one contingency in the 2005 Hobby system, referred to as “Outage #1.” Outage #1 is a transformer outage that would affect 1,782 buses representing approximately 37,456 kW of load under normal summer peak conditions. For this block there are 16 tie switches connecting to alternate sources. Again, the objective was to find ways to reduce the impact of this outage (and the others considered here) possibly with optimized system configuration under contingency conditions or with DER additions. 135

Restoration following Outage #1 via a single switch closure would minimize the impact of this outage on customers. In evaluating restoration following Outage #1 via a single switch closure alone, with no other measures, across a variety of operating conditions, the researchers found four switches that could be closed under any conditions without collapse and three that could not be closed under any conditions. Note that in the reliability assessment above, the researchers considered a path to an alternate source as “available” if the destination circuit loaded at less than 65% of its emergency rating, and where the posited load shift would be a partial circuit. Here the researchers consider a path to an alternative source as “available” at least initially simply considering whether it can accept a large load shift (in this case the entire affected load block) in a feasible power flow simulation that will converge to a solution. Under off‐peak conditions, the least demanding, the post‐closure drop in voltage at the point of connection ranged from 1.3% to over 14%; in the case of 6 of the 13 “feasible” switches, the voltage drop was less than 10%. Under super‐peak conditions, the most demanding, the post‐closure voltage drop at the point of connection was less than 10% for each of the four “feasible” connections.

The researchers next evaluated restoration following Outage #1 via a single switch closure with the benefit of optimization using GRIDfast™ . Specifically, the researchers used GRIDfast™ to re‐optimize the system under each post‐contingency switch closure to see if this would make available more single‐switch restoration choices, arguably enhancing reliability. In this case, the researchers implemented recontrols with flow minimization incorporated directly into the optimization objective function, along with voltage deviation minimization. This is a departure from the objective function used in the other tasks in this project.

The researchers found that the same switches could be closed with feasible power flow solutions under any operating conditions, and the same three could not be closed under any conditions, even with the benefit of GRIDfast™ post‐contingency optimization.

The researchers did find that, under off‐peak conditions with GRIDfast™ optimization, the number of switches among the 13 “feasible” switch closures with post‐closure voltage drops of less than 10% increased from six to nine. Under super‐peak conditions, the four "feasible" switch closures still had post‐closure voltage drops of less than 10% with GRIDfast™ optimization. Thus, post‐contingency optimization using GRIDfast™ had a slight beneficial impact on the available single‐switch restoration options.

Having assessed "feasibility" in a power flow sense, the researchers next looked at the substation overload ramifications of single‐switch restorations for Outage #1. To reiterate, in the reliability assessment above, the researchers considered an alternate feed as available to accept a partial‐circuit load shift if no individual segments of the serving circuit are loaded at greater than 65% of their emergency ratings. Earlier the researchers had considered an alternate feed as available to accept the entire load block through a single switch closure if the post‐contingency configuration would converge in a power flow solution. Now the researchers assessed these alternate feeds in terms of the loading on the transformer taking on the shifted load as well. 136

Under normal summer peak conditions, slightly less demanding than super‐peak conditions, the researchers found that of five nominally feasible single‐switch restorations for Outage #1 that could be completed without collapse, all did cause an overload of the transformer serving the receiving circuit. Under off‐peak conditions, four of the seven of the nominally feasible single switch restorations for Outage #1 would result in overloads of the receiving transformer.

Because Outage #1 impacts such a large load block, the researchers considered other outages, referred to as Outage #3, Outage #4, and Outage #5. These are also transformer bank outages, but smaller banks affecting less connected load. Outage #4 affects only one circuit, while Outage #3 affects two circuits, and Outage #5 affects three circuits.

Under normal summer peak conditions the researchers found that there is one single‐switch restoration for Outage #3 that results in a "feasible" power flow solution, but that also results in overload of the receiving transformer. The researchers found that there are nine nominally feasible single‐switch restorations for Outage #4, none of which overloads the receiving transformer. For Outage #5 the researchers found 15 nominally feasible single‐switch restorations, one of which results in an overload of the receiving transformer.

The researchers found that under off‐peak conditions all of the nominally feasible single‐switch restorations for Outages #3, #4, and #5 could be implemented without overloading the receiving transformers. However, of the seven nominal feasible single‐switch restoration of Outage #1 under off‐peak conditions, all but three would result in an overload of the receiving transformer.

The researchers next considered the potential benefits from DER additions in either opening up more "feasible" single‐switch post‐contingency restorations or in mitigating overloads of receiving transformers under post‐contingency load shifts, where these overloads would otherwise occur. The researchers considered both demand response (DR) and distributed generation (DG), using the same DR and DG citing criteria and limitations described in Section 2.2.6. However, in this case, the researchers identified and ranked DR and DG additions explicitly based on their ability to relieve overloads, with minimization of flow exceeding rated capacity again incorporated directly into the optimization objective function.

The researchers found that under summer peak conditions and Outage #1, DR, and DG additions under the limits of this project’s rubric could not overcome the transformer overloads that would result from any of the single‐switch restorations. The researchers also found that with Outage #3 DR additions did not represent enough capacity to relieve the expected load‐shift transformer overloads. However, the researchers did find that with ideally placed DG, the one feasible single switch restoration could be implemented without overloading of the receiving transformer.

The researchers also found that under off‐peak conditions, ideally placed DG would mitigate the overloads posited for single‐switch restoration of Outage #1. Again, the researchers found that DR would not provide enough capacity to relieve these overloads. Therefore, through this the researchers have identified specific DG projects that, in addition to their other benefits, also as a group provide the benefit of creating a single‐switch restoration option for Outage #3 under normal summer peak conditions, yielding a specific reliability benefit. There is another set of DG projects with the added benefit of expanding the single‐switch restoration alternatives for Outage #1 under off‐peak conditions, again, yielding a specific reliability benefit.

Table 32 lists the individual switches that would be involved in the achievable single‐switch restorations for each of the outages considered. In light of the ability of these 33 switches to restore entire load blocks with a single closure, these might be excellent choices for remote operation.

In summary, these results identify a set of restoration actions for several outages, under both peak and off‐peak conditions that may be implemented with a single switch while not violating transformer loading limits, permitting the fastest, simplest service restoration. The researchers have also identified a group of DG projects that enable or enhance these restorations for specific contingencies.

Single‐switch restoration of a load block following a contingency is arguably an extreme approach for service restoration in a system lacking designed‐in surplus capacity for that purpose. It has the benefit, however, of the minimum number of steps to restore affected customers. Therefore, it may be appealing where possible, particularly following transformer bank outages that may otherwise require many switching steps to redistribute affected load. Through the process illustrated here the researchers were able to identify single‐switch restorations that would not result in an infeasible power flow solution or a transformer overload condition for several of the outage scenarios and under both on‐peak and off‐peak conditions. GRIDfast™ optimization of existing controls with a load‐minimizing component in the optimization objective function did not meaningfully affect the single‐switch restoration opportunities. However, DG additions identified based on a GRIDfast™ analysis incorporating load minimization in the objective function did expand single‐switch restoration opportunities in boundary cases such as Outage #3.